Evaluation of Operating Procedures in Carbon TerraVault's Monterey Formation A1-A2 Permit Application

This evaluation for the proposed Carbon TerraVault (CTV)-Elk Hills Class VI geologic sequestration project summarizes our review of proposed operating procedures for injection wells 355-7R and 357-7R, per 40 CFR 146.82(a)(7),(9),(10) and 146.88. CTV submitted information about Wells 355-7R and 357-7R in their initial Class VI permit application narrative dated August 30, 2021 and submitted additional information about injection Well 355-7R in an amended Narrative (Attachment A2, submitted on December 2, 2021). Operation of the two injection wells is evaluated in this single report. Our review identifies preliminary questions and includes requests for supplemental information from the applicant. This evaluation of the proposed operating conditions, particularly injection rates and pressures, was performed in conjunction with EPA's evaluation of the applicant's AoR delineation modeling (which is documented in a separate report).

The proposed operational procedures (which appear to be specific to Well 357-7R) are described on page 47 of the initial Narrative and summarized in Table 8, which is replicated below:

Table 8 of initial Narrative (for Well 357-7R)		
Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Injection Pressure		
Surface	3,800	Psig
Downhole	6,100	Psig
Average Injection Pressure		
Surface	1,600	Psig
Downhole	4,100	Psig
Maximum Injection Rate	30 per well	Mmscfd
Average Injection Rate	10-15 per well	Mmscfd
Maximum Injection Volume and/or Mass	10 Million	Tonnes
Average Injection Volume and/or Mass	8 Million	Tonnes
Annulus Pressure	3,730 @ packer	Psig
Annulus Pressure/Tubing Differential	370@packer @ average injection condition	Psig

The proposed operational procedures for Well 355-7R are described in the amended Narrative (Attachment A2) and summarized in a revised Table 8, which is replicated below:

Table 8 of updated Narrative (for Well 355-7R)		
Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Injection Pressure		
Surface	2,900	Psig
Downhole	6,108	Psig
Injection Pressure		
Surface Average / Maximum	1,400/1,600	Psig
Downhole Average / Maximum	4,300 / 4,516	Psig
Maximum Injection Rate	30 per well	Mmscfd
Average Injection Rate	10-15 per well	Mmscfd
Maximum Injection Volume and/or Mass	10 Million	Tonnes
Average Injection Volume and/or Mass	8 Million	Tonnes
Annulus Pressure	3,720 @ packer	Psig
Annulus Pressure/Tubing Differential	578@packer @ average injection condition	Psig

Injection Pressure

The basis for the proposed maximum injection pressure (MAIP) is described in Attachment B – the AoR and Corrective Action Plan (AoR CA). CTV states that the MAIP will be below 90% of the fracture pressure of the Monterey Formation at the base of the Reef Ridge Shale confining zone, and is calculated as follows:

$$8{,}150psi \times 0.9psi/ft = 7{,}335\ psi$$

Where:

Fracture pressure (Fp) at base of confining zone = 8,150psi

Safety factor = 0.9 (90%)

Tables 6 and 7 of the AoR CA provide fracture gradients and fracture pressures for the Monterey Formation A1-A2 reservoir, and are replicated below:

Table 6		
Interval	**Fracture Gradient psi/ft**	**Fracture Pressure (psi) at base of Reef Ridge Shale (8,403 ft)**
Monterey Formation A1-A2	0.97	8,150

Table 7		
Injection Pressure Details	**Injection Well 1 357-7R**	**Injection Well 2 355-7R**
Fracture gradient (psi/ft)	0.97	0.97
Maximum injection pressure (90% of fracture pressure) (psi)	7,335	7,335
Elevation corresponding to maximum injection pressure (ft MSL)	8,403	8,403
Elevation at the top of the perforated interval (ft MSL)	8,485	8,462
Calculated maximum injection pressure at the top of the perforated interval (psi)	7,407	7,387
Planned maximum injection pressure / gradient (top of perforations)	4,500 / 0.53	4,500 / 0.53

The maximum injection pressure listed in Table 7 of the AoR CA for injection wells 357-7R and 355-7R does not correspond to the maximum injection pressure in Table 8 of the Narrative or the amended Narrative. Additionally, the proposed injection pressures of 4,500 psi in Table 7 of the AoR CA exceed the proposed average injection pressures of 4,100 psi, listed in Table 8 of the Narrative. It appears that, regardless of the discrepancy in maximum injection pressures, CTV proposes to operate at an injection pressure of 4,100 – 4,500 psi, well below 90% of the injection zone fracture pressure. However, the proposed injection pressures will need to be confirmed as being below 90% of the fracture pressure at the top of the perforations (i.e., within the Monterey Formation injection zone), and the discrepancy in maximum injection pressures will need to be resolved.

CTV states in the AoR CA that their current Class II UIC permit mandates a maximum operating pressure gradient of 0.80 psi/ft unless additional testing indicates a higher gradient. It appears that CTV conducted a test(s) to obtain a higher fracture gradient, 0.9 psi/ft, as seen in Table 6 of the AoR CA, above. However, these tests are not described in the application and will need to be provided for validation of the fracture pressure of the injection and confining zones and the corresponding maximum injection pressures. A question for the applicant regarding this topic is included in the AoR CA Evaluation.

Questions/Requests for the applicant:

- *Please provide separate stand-alone versions of Attachment A for Well 357-7R and Well 355-7R that describe operating conditions. The attachments should include the following: injection well operating conditions (e.g., a tabular description of surface and bottomhole maximum injection pressures, annulus pressure, annulus pressure/tubing differential, and the maximum CO_2 injection rate); how the maximum injection pressure was determined; a description of routine shutdown procedures; and tables summarizing reporting of well and project-related monitoring.*
- *Attachment E (the PISC and Site Closure Plan), page 1 states that the Monterey Formation A1-A2 reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. Please clarify that injection limits (e.g., pressures) will be based on the fracture pressure of the injection zone.*

- *The maximum downhole injection pressures in Table 8 of the Narrative (6,100 psi for Well 357-7R and 6,108 psi for Well 355-7R) do not correspond to the pressure listed in Table 7 of the AoR CA (7,335 psi). Please reconcile this difference and update the tables as needed.*
- *Please confirm that the maximum downhole injection pressures in Table 8 of the Narrative (6,100 psi for Well 357-7R and 6,108 psi for Well 355-7R) are correct, i.e., that there is a 900 psi difference in surface pressure and an 8 psi difference in downhole pressure.*
- *Please provide the fracture pressure (psi) at the top of the perforations in injection wells 357-7R and 355-7R within the Monterey Formation and confirm the proposed maximum injection pressure does not exceed 90% of this value, per the requirement at 40 CFR 146.88(a).*

Annulus Pressure and Annulus/Tubing Pressure Differential

The applicant notes in Attachment C (the Testing and Monitoring Plan) that the surface pressure of the casing-tubing annulus for injection wells 357-7R and 355-7R will remain between 0 – 800 psi during injection operations.

Regarding Well 357-7R and in Table 8 of the initial Narrative excerpted above, the annulus pressure/tubing differential is 370 psi at the packer at the average injection pressure of 4,100 psi, resulting in a 3,730 psi annulus pressure at the packer. Table 8 defines the 3,730 psi annulus pressure as a proposed limit or permitted value, however this pressure occurs at the average injection pressure of 4,100 psi. Clarification is needed to ensure that the 3,730 psi annulus pressure at the packer is indeed a proposed maximum limit and corresponds to a maximum injection pressure. Additionally, the applicant will need to confirm that the 3,730 psi annulus pressure at the packer is within the 0 – 800 psi annulus pressure range at the surface, as noted in Attachment C. If the above is confirmed, the annulus pressure of 3,730 psi at the packer is well below the tubing and packer burst strengths of 12,450 psi and 8,160 psi respectively, as noted in Table 7 of Attachment A, which is excerpted below.

Casing specifications for Well 357-7R (Table 6 of Attachment A)

Table 6. Casing details.

Casing String	Casing Depth	Borehole Diameter	Wall Thickness	External Diameter	Casing Material	String Weight
Conductor	60	24	0.55	20	J-55	94
Surface	501	17.5	0.33	13.375	H-80	48
Intermediate	3516	12.25	0.395	9.625	N-80	40
Long String	2,953	8.75	0.317	7	N-80	23
	6,158	8.75	0.362	7	N-80	26
	6,158 – 8,990	8.75	0.408	7	N-80	29

Tubing specifications for Well 357-7R (Table 7 of Attachment A)

Table 7. Tubing and packer details.

Material	Setting Depth	Tensile Strength	Burst Strength	Collapse Strength	Material
Tubing	8,454	105,000	12,450	12,760	13 CR-95
Packer	8,447	10,000	8,160	7,020	Baker-Hornet, Ni plated

Regarding Well 355-7R, the same clarifications need to be made regarding proposed maximum annulus pressure and the equivalent surface pressure as described for well 357-7R above. In Table 8 of the updated Narrative, the annulus pressure/tubing differential is 578 psi at the packer at the average injection pressure of 4,300 psi, resulting in a 3,720 psi annulus pressure at the packer. Clarification is needed to ensure that the 3,720 psi annulus pressure at the packer is indeed a proposed maximum limit and corresponds to a maximum injection pressure. Additionally, the applicant will need to confirm that the 3,720 psi annulus pressure at the packer is within the 0 – 800 psi annulus pressure range at the surface, as noted in Attachment C. If the above is confirmed, the annulus pressure of 3,720 psi at the packer is well below the tubing and packer burst strengths of 9,020 psi and 8,000 psi respectively, as noted in Table 6 and 7 of Attachment A2, excerpted below.

Tubing specifications for Well 355-7R (Table 6 of Attachment A2)

Table 6. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	8,398	80	3.920	135	L-80	Long	9,020	8,540

Packer specifications for Well 355-7R (Table 7 of Attachment A2)

Table 7. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Baker-Hornet, Ni plated	8,403	95.4	23-29	6.000	2.920

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
100,000	8,000	8,000	6.466	6.184

Questions/Requests for the applicant:

- *For injection well 357-7R, please clarify that a 3,730 psi annulus pressure at the packer is the proposed maximum limit and that it corresponds with the maximum injection pressure. Additionally, please confirm that a 3,730 psi annulus pressure at the packer is within the 0 – 800 psi annulus pressure range at the surface, as noted in Attachment C.*
- *For injection well 355-7R, please clarify that a 3,720 psi annulus pressure at the packer is the proposed maximum limit and that it corresponds with the maximum injection pressure.*

Additionally, please confirm that a 3,720 psi annulus pressure at the packer is within the 0 – 800 psi annulus pressure range at the surface, as noted in Attachment C.

- *The outside diameter of the injection tubing for Well 355-7R (on Table 6 of Narrative A2) is stated as "00." Please correct.*

Maximum CO_2 Injection Rate

The applicant proposes a daily CO_2 injection rate of 648 to 1,917 tons per day, which equates to 236,520 to 699,705 tons/year (or 3.5 – 10.5 million tons over the planned 15-year injection phase of the project) as seen in Table 5 of the AoR CA and excerpted below. However, the applicant notes in the Narrative that the storage capacity of the Monterey Formation A1-A2 reservoir is approximately 8 – 10 million tonnes of CO_2 based on computational modeling results. The maximum storage capacity of 10 million tonnes of CO_2 is slightly less than the projected maximum volume of 10.5 million tonnes of CO_2 based on daily injection rates as seen in Table 5 below (assuming injection activities will occur 365 days per year). Based on an evaluation of the AoR delineation modeling and geologic site characterization, it appears that the injection and confining zones are appropriately characterized; however, the range of proposed daily injection rates allow for the exceedance of the modeled storage capacity. The applicant should reconcile this inconsistency and provide an updated range of daily CO_2 injection rates that satisfies the modeled CO_2 storage capacity. See the AoR CA evaluation report for additional discussion.

Table 5. Operating details.

Operating Information	Injection Well 1 357-7R	Injection Well 2 355-7R
Location (global coordinates) X Y	35.32802963 -119.5449982	35.33139038 -119.5441437
Model coordinates (ft) X Y	6,100,956.63 2,308,944.30	6,101,103 2,310,474
No. of perforated intervals	7	4
Perforated interval (ft MSL) Z top Z bottom	7,728 8,010	7,774 7,949
Wellbore diameter (in.)	7	7
Planned injection period Start End	02/01/2024 04/01/2039	02/01/2024 04/01/2039
Injection duration (years)	15	15
Injection rate (t/day)*	648 – 1,917	648 – 1,917

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

In the Testing and Monitoring Plan (pg. 5), CTV states that the volume of CO_2 injected into the Monterey Formation A1-A2 Sands will be calculated from the injection flow rate and CO_2 density, and that density will be determined from the Massachusetts Institute of Technology's CO_2 Thermophysical Calculator (https://sequestration.mit.edu/tools/index.html). However, upon investigation of the online calculator, it appears to no longer be operational. The applicant should provide another method by which the CO_2 density will be calculated.

Questions/Requests for the applicant:

- *Please include a description of standard operating procedures to ensure that the maximum daily injection rate will not be exceeded.*
- *Please update the daily CO_2 injection volumes in Table 5 of the AoR CA to ensure they are consistent with the modeled cumulative injection volumes of 8 – 10 million tonnes of CO_2 over 15 years.*
- *The Massachusetts Institute of Technology's CO_2 Thermophysical Calculator is no longer operational. Please revise the methodology by which the CO_2 density will be calculated.*

Shutdown Procedures

The applicant notes in Attachment F, the Emergency and Remedial Response Plan, that the shutdown plan will be initiated in response to multiple risk scenarios, including well integrity failure, monitoring equipment failure, natural disasters, USDW contamination, CO_2 leakage, and seismic events. The Plan defines "initiating the shutdown plan" as immediately ceasing injection. It also states (on pg 1) that "gradual cessation of injection" may be appropriate in certain circumstances if approved by the UIC Program Director. However, the application does not describe procedures for shutting down the well, either for routine workovers or in response to emergency events (other than those that warrant an immediate shutdown). Documenting such procedures will ensure that procedures are in place to shut down the well in a manner that will not damage the well and cause a mechanical integrity issue.

Questions/Requests for the applicant:

- *Please describe the procedures for "gradual cessation of injection," i.e., the rate of injection volume reduction over a specified number of days.*
- *Please also describe routine well shutdown procedures (e.g., for well workovers), and if these would be the same as the gradual shutdown procedures discussed above.*

Automated Shutdown System

The applicant notes in Attachment F, the Emergency and Remedial Response Plan, that the automatic shutdown devices are activated if wellhead pressure exceeds the specified shutdown pressure listed in the permit, or if the annulus pressure indicates a loss of external or internal well containment. However, standard operating procedures that support the automated shutdown system are not provided.

Questions/Requests for the applicant:

- *Please include standard operating procedures to support the automated shutdown system.*